Request IR-1:

(a) **Please list the loading conditions and rated capacity of the proposed transmission lines, since 2019, and provide the connection diagrams to explain the connections of the proposed transmission systems and explain the function and rating of each listed equipment.**

 (i) **Include related equipment from substations.**

 (ii) **Use plain language to explain the function of each equipment.**

(b) **Please explain the general criteria that may limit the load carrying capacity of the transmission systems, including but not limited to environmental conditions, conductor properties and conditions, equipment properties and conditions, structural properties and conditions, etc.**

(c) **Please estimate the load carrying capacity increase on the proposed transmission lines after installing the sensors and explain why the sensors on the transmission lines will help improve the load capacity, and the criteria in b) above will not be a limitation to obstruct the proposed load increase.**

Response IR-1:

(a) Please refer to Attachment 1 and Attachment 2.

(b) In Attachment 2, the impact of substation devices (such as switches, current transformers, breakers, transducers, and protection relays) on transmission line ratings is provided (please refer to page 2 of Attachment 2, columns breaker, switch, current transformer, and protection). Expanding on this, the following explains the general criteria that may limit the load-carrying capacity of transmission systems, focusing on the conductor and its maximum operating temperature (which is provided on page 2 of Attachment 2, column conductor).

Transmission line conductor ratings are calculated on a seasonal basis using industry-accepted thermal methodologies, consistent with IEEE 738. The following factors are considered when determining conductor ampacity:

- Conductor type – Affects line rating by determining the conductor's electrical resistance, diameter, emissivity, and absorptivity, which together govern heat balance and sag limits in ampacity calculations.

- Wind speed – Lower wind speed reduces convective cooling; zero or low wind conditions often define the worst-case ampacity.

- Wind direction – Wind perpendicular to the conductor provides maximum cooling, while wind parallel to the conductor provides minimal cooling.

- Solar radiation – Direct solar heating increases conductor temperature, reducing available thermal margin.

- Air density / altitude – Lower air density at higher elevations reduces convective cooling efficiency.

- Ambient temperature – Higher ambient temperatures reduce the conductor's ability to dissipate heat, resulting in lower allowable ampacity.

- Maximum operating temperature of the conductor – A value determined by Transmission Design based on sag-clearance requirements, structural loading limits, and conductor mechanical and thermal properties.

Static seasonal line ratings are calculated without ice accretion. Decisions to derate a line due to ice risk are made by the Energy Control Center based on visual inspection, weather conditions, and overall system risk.

- Ice accretion – Adds mechanical load and increases sag; may indirectly limit allowable operating temperature to maintain clearances under combined loading conditions.

In summary, the maximum allowable conductor operating temperature is established by NS Power's Transmission Design group considering multiple factors, including conductor mechanical and thermal properties, tower and structure design, and sag-clearance limits. This design-approved maximum temperature is then used to determine line ampacity under various environmental conditions, ensuring the conductor temperature does not exceed its allowable limit.

(c) Consistent with the design and functionality of DLR technology, the load carrying capacity of each line will change dynamically based on the actual environmental conditions present along the line. Based on estimates from the vendor, potential increases in line capacity could range up to +20% for 90% of the year and +40% for 50% of the year, but the specifics of the line, environmental conditions, and non-environmental restrictions (as detailed in part (b) above), could result in different capacity changes.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Information from PI data. All values in MW														
Line	2025		2024		2023		2022		2021		2020		2019	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
L-8001	-217.9	192.7	NA	NA	-385.7	198	-372.5	122.4	-279.8	129.1	-282.5	144	-256.1	111.4
L-8004	-32.2	416.7	NA	NA	-17.3	425.1	-42.5	434	-55.7	387.7	-73.9	354.3	-61.1	458.6
L-7005	-13.1	174.5	NA	NA	-19.9	192.1	-17.8	277.3	-29.5	171.4	-28.1	167.9	-30.7	185.2
L-7004	-52.6	158.5	NA	NA	-21.3	166.1	-23.1	176.3	-52.2	161.8	-44.2	157.9	-35	179.2
L-7003	-13.9	155.9	NA	NA	-21.5	163	-23.4	174.5	-36.5	157.1	-29.1	153.9	-29.1	177.2
L-6515A	-55.6	85.7	NA	NA	-57.8	108.1	-61.2	91.4	-57.4	84.3	-61.5	87.5	-79.8	95.9
L-6515B	-58.6	79.2	NA	NA	-60.8	101.5	-65.3	84.7	-60.2	77.9	-65.4	80.7	-85.8	90.8

NOTES:

Data from October 2023 to April 25 2025 is not available due to cyber incident.

Positive and negative value is direction of the flow from point of reference.

The loading capability of the proposed transmission lines, are provided in the summary table 1 below for the current line loading. The 2019 ratings are provided in summary table 2. It can be observed that there are significant differences between the ratings. This could be from line upgrades or LIDAR surveys or most recently, recalculation of the lines capability using 4 seasons and following updated IEEE standards such as standard 738.

Summary table 1 – seasonal ratings for selected lines 2025

LINE	FROM	TO	HOT (MVA)	WARM (MVA)	COOL (MVA)	COLD (MVA)
L-6515A	2C Pt. Hastings	100C Cape Porcupine	110	145	172	204
L-6515B	100C Cape Porcupine	4C Lochaber Rd.	110	145	172	204
L-7003	3C Pt. Hastings EHV	67N Onslow EHV	285	311	318	387
L-7004	3C Pt. Hastings EHV	91N Dalhousie Mountain	241	279	318	365
L-7005	3C Pt. Hastings EHV	67N Onslow EHV	429	470	523	588
L-8001	Memramcook NB	67N Onslow EHV	650	884	1044	1203
L-8004	79N Hopewell	101S Woodbine	1093	1115	1197	1300

Summary: Seasonal MVA ratings (Hot, Warm, Cool, Cold) for the specified lines, extracted from *Transmission Line Ratings* (last updated October 15, 2025).

Summary table 2 – seasonal ratings for selected lines 2019

LINE	FROM	TO	SUMMER (MVA)	WINTER (MVA)
L-6515A	2C Pt. Hastings	100C Cape Porcupine	110	143
L-6515B	100C Cape Porcupine	4C Lochaber Rd.	B section did not exist in 2019.	
L-7003	3C Pt. Hastings EHV	67N Onslow EHV	233	307
L-7004	3C Pt. Hastings EHV	91N Dalhousie Mountain	233	340
L-7005	3C Pt. Hastings EHV	67N Onslow EHV	398	398
L-8001	Memramcook NB	67N Onslow EHV	554	554
L-8004	79N Hopewell	101S Woodbine	990	990

Summary: Seasonal MVA ratings (Summer and Winter) for the specified lines, extracted from *Transmission Line Ratings* (2019-10-16).

Detailed Table – NSPI Transmission Line Ratings 2025

NSPI Transmission Line Ratings

Last Updated: 2025-10-15

LINE	STATION	CONDUCTOR						BREAKER	SWITCH	CURRENT TRANSFORMER						PROTECTION
		TYPE	MAX OPERATING TEMP. (°C)	HOT SEASON RATING 30°C (MVA)	WARM SEASON RATING 15°C (MVA)	COOL SEASON RATING 5°C (MVA)	COLD SEASON RATING -10°C (MVA)	100% NAME PLATE (MVA)	100% NAME PLATE (MVA)	RELAYING Ratio	R.F.	MVA	FULL SCALE METERING Ratio	T/R	MVA	TRIP MVA
L-6515a	2C Pt. Hastings	ACSR 556.5 Dove	50	110	145	172	204	287	287	1200	2	574	1200	R	574	651
	100C Cape Porcupine								143				NA			
L-6515b	100C Cape Porcupine	ACSR 556.5 Dove	50	110	145	172	204		143				NA			
	4C Lochaber Rd.							478	143	600	2.5	358	600	T	173	652
L-7003	3C Pt. Hastings EHV	ACSR 556 Dove	60	285	311	318	387	797	797	800	2	637	1000	T	462	550
	67N Onslow EHV							797	797	800	2	637	1000	T	462	550
L-7004	3C Pt. Hastings EHV	ACSR 556 Dove	60	241	279	318	365	797	797	800	2	637	1000	T	462	710
	91N Dalhousie Mountain							797	797	800	2.5	797	800	R	797	710
L-7005	3C Pt. Hastings EHV	ACSR 1113 Beaumont	70	429	470	523	588	797	797	800	2	637	1000	T	462	656
	67N Onslow EHV							797	797	800	2	637	800	T	385	597
L-8001	Memramcook NB	ACSR 2x795 Drake / ACSR 2156 Bluebird	49 / 60	650	884	1044	1203						1200	T	831	
	67N Onslow EHV							1793	1195	800	2	956	800	T	554	1991
L-8004	79N Hopewell	Type 41 SDC / ACSR 2 x 1113 Beaumont	95 / 120	1093	1115	1197	1300	1793	1793	1200	2	1434	800	T	554	1606
	101S Woodbine							1793	1793	2000	2	2390	2000	R	1617	1567

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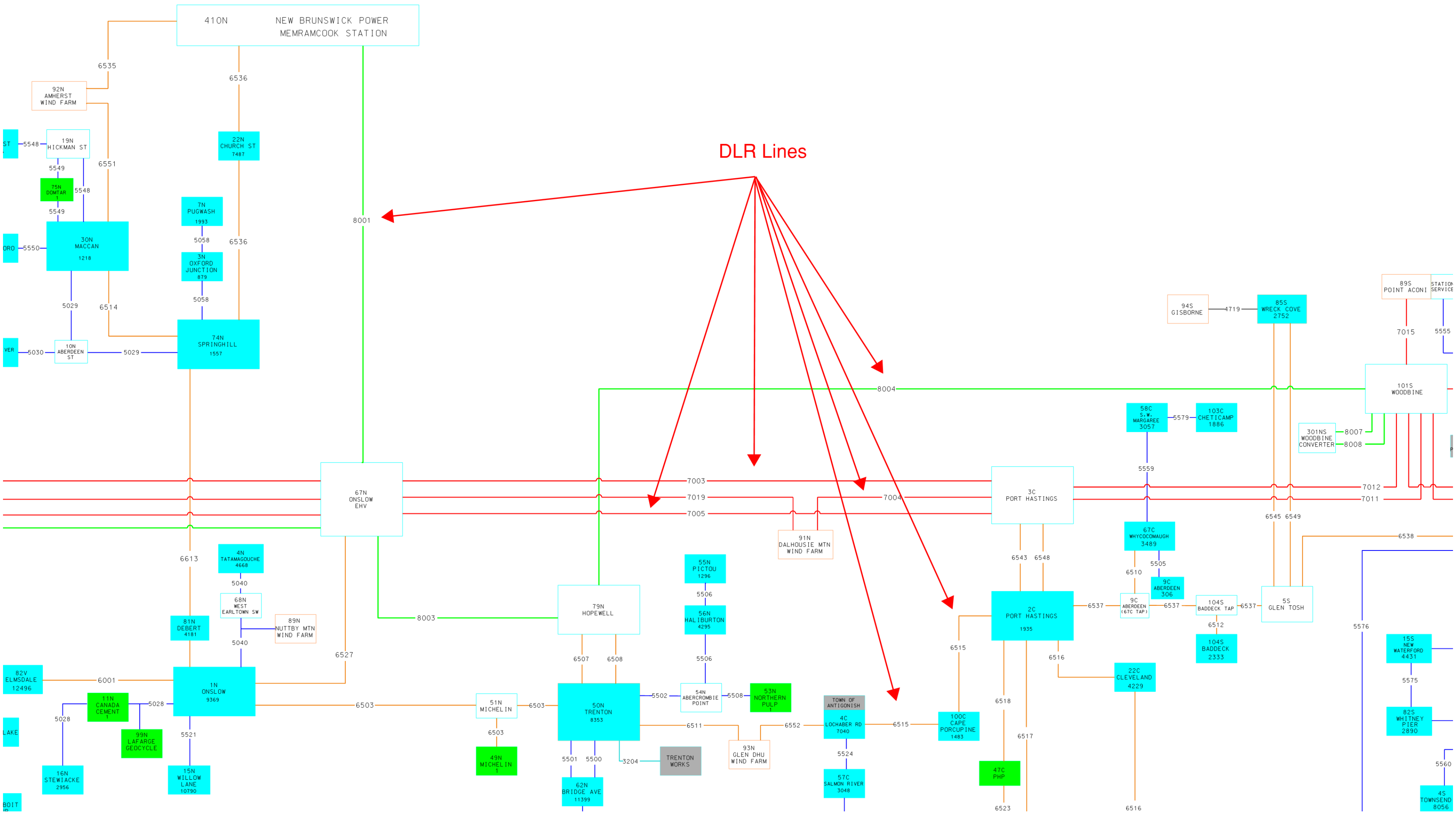


The following section shows substation equipment associated with each line.

Substation Equipment that impacts line rating:

Breaker: Interrupting device, the continuous current rating of the breaker must be considered for the line rating.

Switch: Disconnect device, the continuous current rating of the switch must be considered for the line rating.

Current Transformer: Measurement device transforms line current to a smaller value that instrumentation can read. Continuous current rating of the current transformer must be considered. Additionally, its measuring capability must be considered to provide accurate reading to the associated devices such as relays and metering transducers.

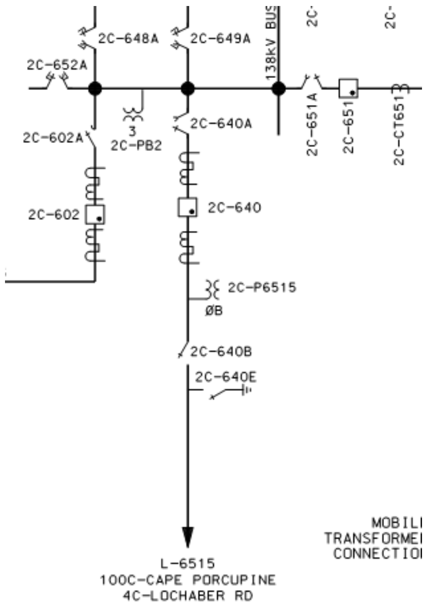
Protection relays: Asset which makes decision to operate the breaker to protect the system against abnormal conditions. Can also be used to pass metering information to SCADA. If the protection limit is reached this will result in a breaker trip and the line becoming out of service. This limit is considered in the line rating.

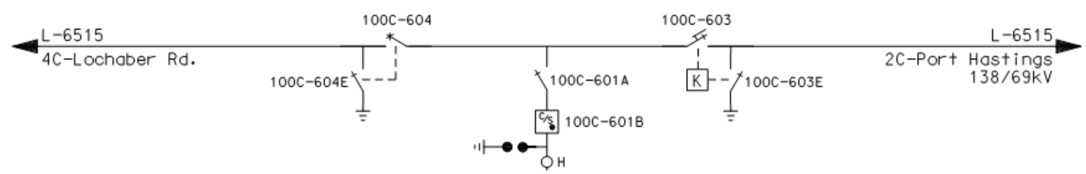
Metering Transducer: Converts readings from the current transformers to provide values to SCADA. If the metering transducer saturates (can’t read any higher), the current flows on the line unknown. This can lead to overloading lines without knowing it. For this reason, the transducer is considered in the line rating.

Note: Metering values impact line rating as this is the real time information that the SCADA system uses for alarming and the operator observes for flows on the lines.

L-6515a

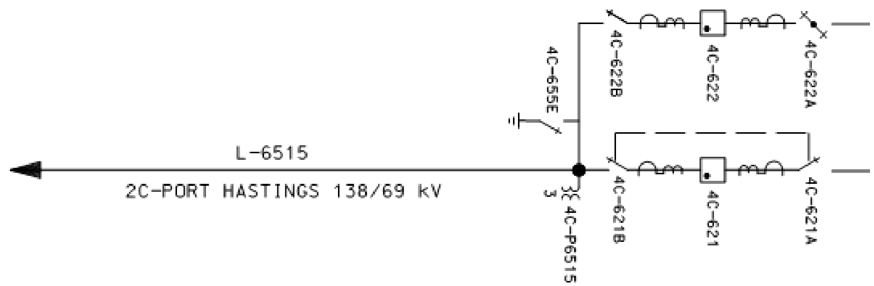
Substation Equipment related to this line 2C-640 breaker, 2C-640A switch, 2C-640B switch and associated current transformer. Also considered, 100C-603 Switch. Protection and metering is provided by the protection relays at 2C and this is factored into the line rating.

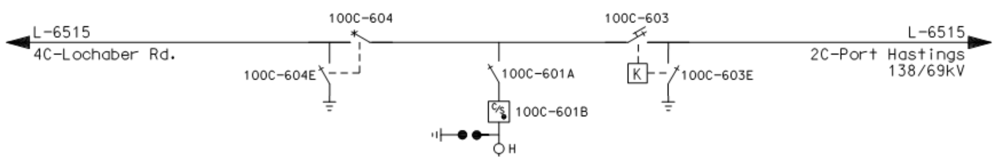




L-6515b

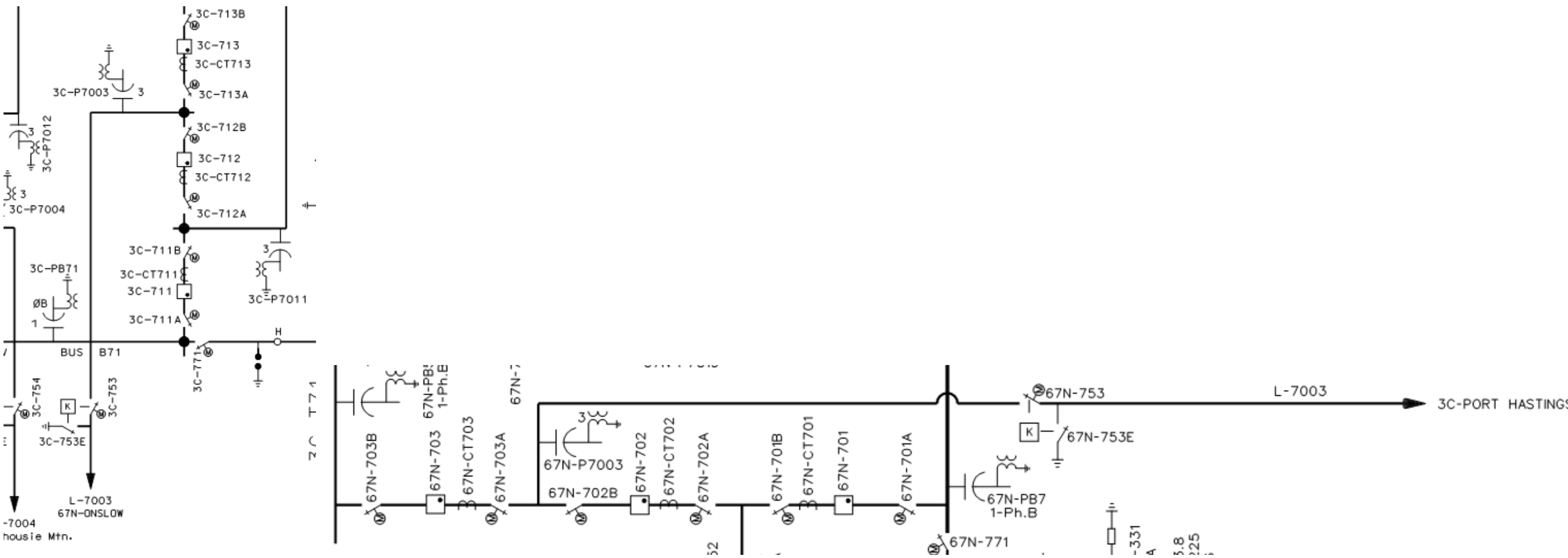
Substation Equipment related to this line are the 4C-622 and 4C-621 breaker. Additionally, the switches 4C-622A, 4C-622B, 4C-621A, 4C-621B and 100C-604 are associated with this line. Metering is provided by a transducer at 4C, this along with the line protection relays at 4C are factored into the line rating.





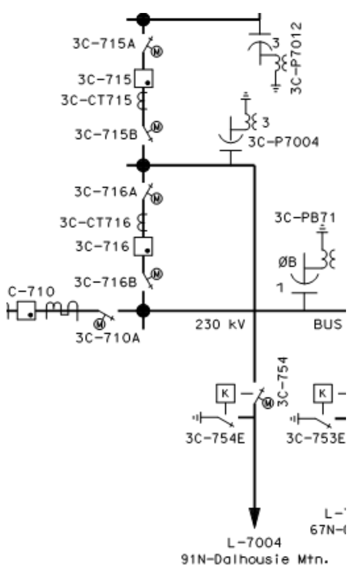
L-7003

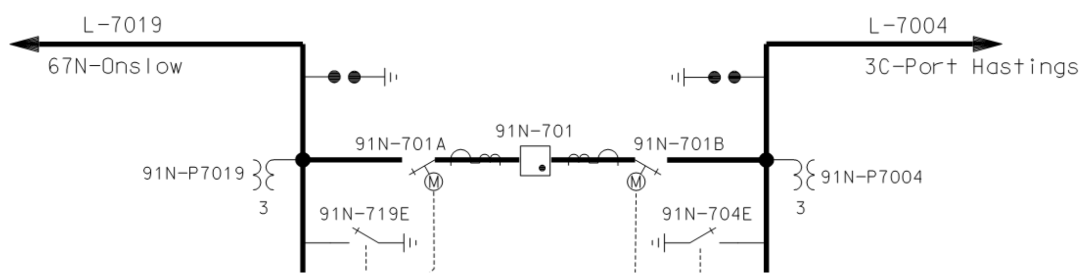
Substation Equipment related to this line are breakers 3C-712, 3C-713, 67N-703 and 67N-702. Current transformers 3C-CT712, 3C-CT713, 67N-CT703 and 67N-CT702 . The following switches are also associated with these lines. 3C-712A, 3C-712B, 3C-713A. 3C-713B, 3C-753, 67N-702A, 67N-702B, 67C-703A. 67N-703B and 67N-753. Transducers provide metering on both ends of this line. This and the line protection relays are factored into the line ratings.



L-7004

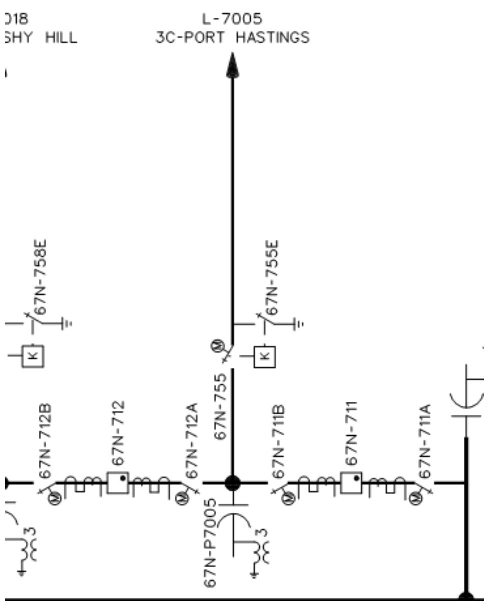
Substation Equipment related to this line are breakers 3C-715, 3C-716 and 91N-701. Current transformers 3C-CT715, 3C-CT716. The following switches are also associated with these lines. 3C-715A, 3C-715B, 3C-716A. 3C-716B, 3C-754 and 91N-701B. The 3C end metering is provided by a transducer and 91N is provided by a protection relay. This and the protection relays on both ends of the line are factored into the line rating.

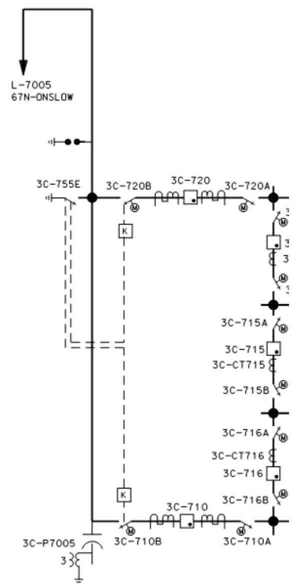




L-7005

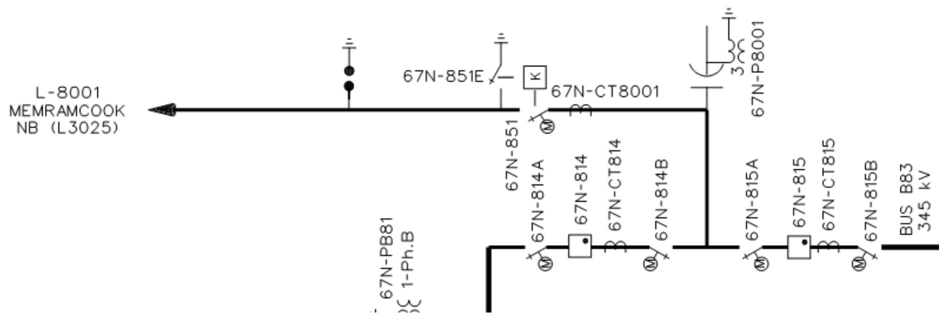
Substation Equipment related to this line are breakers 3C-710, 3C-720, 67N-711 and 67N-712. The following switches are also associated with these lines. 3C-710A, 3C-710B, 3C-720A. 3C-720B, 67N-711A, 67N-711B, 67C-712A, 67N-712B and 67N-755. Transducer metering and line protection on both sides are factored into the rating calculation.





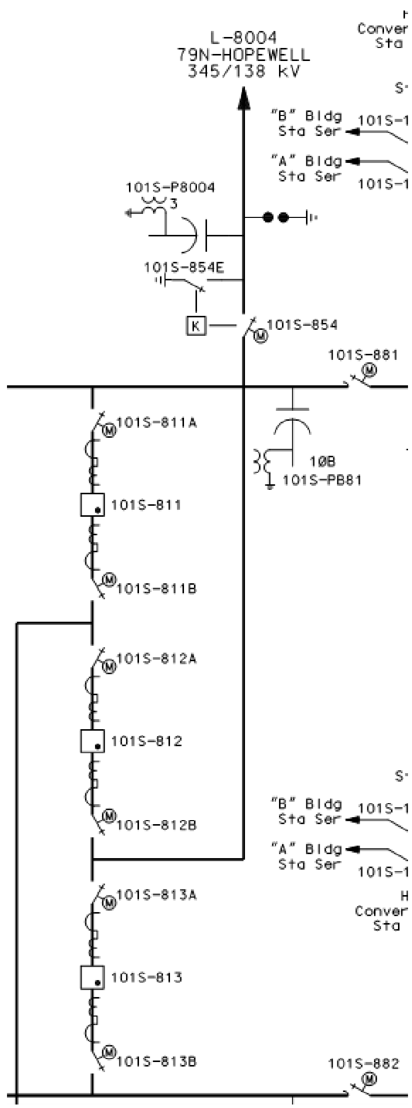
L-8001

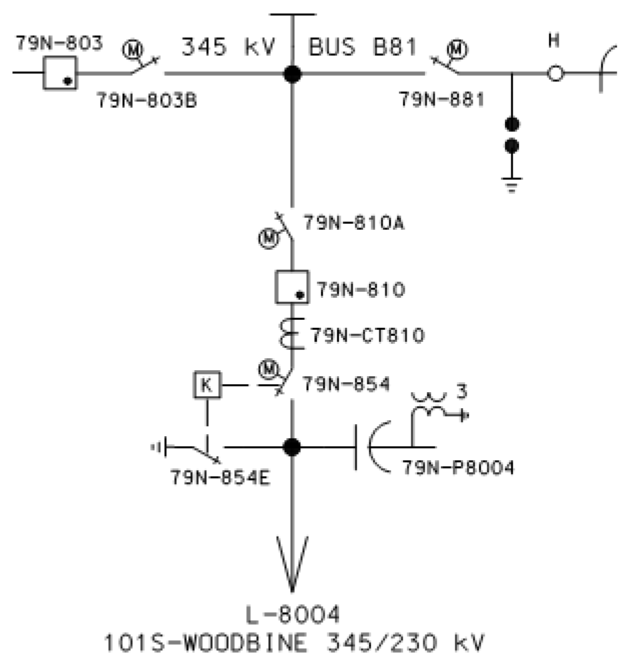
NSPI Substation Equipment related to this line are breakers , 67N-814 and 67N-815. Current transformers 67N-CT814, 67N-CT815 and 67N-CT8001. The following switches are also associated with these lines. 67N-814A, 67N-814B, 67N-815A, 67N-815B and 67N-851. Transducer based metering and line protection are considered in the line rating.



L-8004

Substation Equipment related to this line are breakers 101S-811, 101S-812 and 79N-810. The following switches are also associated with these lines: 101S-811A, 101S-811B, 101S-812A, 101S-812B, 101S-854, 79N-810A and 79N-854. Finally 79N-CT810 is a current transformer which can impact this lines rating. Transducer metering at 79N and relay metering at 101S woodbine along with line protection relay settings are factored into the rating calculation.





Request IR-2:

(a) Please explain if the NSIESO has been notified or involved in the proposed project.

(b) Please clarify the user of the Grid Enhancing Technology (GET) tool, NS Power, NSIESO, or both.

(c) Please explain any training requirements for system operators to operate the new tool and perform Dynamic Line Rating (DLR) operation.

Response IR-2:

(a) Prior to the Phase I transition from NS Power to the IESO Nova Scotia on December 1, 2025, members of the NS Power System Planning team (who have since transitioned to IESO Nova Scotia) were involved in the scoping and planning of this initiative over the past several years.

(b) As the current System Operator, NS Power continues to be responsible for Real Time Operations and therefore is the current intended user of this technology.

(c) System Operator training requirements include a review of documentation on how the DLR sensors and technology platform work and how the MW capacity values from the solution are presented in the existing SCADA system. Operators will also be provided system access and trained on navigating the DLR software platform to view graphical representation of transmission line events identified by the system (i.e. gallop, icing, sag) occurring on sensor equipped transmission lines beyond the MW values that are represented in SCADA.

Request IR-3:

In M09508, IR-24, attachment 1, the vendor noted that there are two methods to manage the data, locally (NS Power) or remotely (vendor), and mentioned two factors, financial and safety.

(a) If the accepted proposal operates under a similar method, please explain who would manage the data collection and analysis system: NS Power, NSIESO, or the vendor?

(b) Please explain how NS Power and NSIESO will share access to data.

(c) Please provide examples to explain how NS Power or NSIESO would apply the new GET system during daily operation.

(d) Please explain the benefits for rate payers.

Response IR-3:

(a) Assuming the question is referencing Solution Hosting Services, NS Power is implementing a cloud-hosted solution through the vendor, and the data is integrated into the NS Power SCADA system. The vendor manages the data collection and analysis system.

(b) At this time, data access is limited to NS Power and the vendor and is not shared with other parties.

(c) NS Power will utilize the DLR solution data through integration to its SCADA system for real-time visibility of line capacity ratings. Operators will log into the Vendor Operating System Platform to view detailed information relating to events occurring on sensor enabled lines related to conditions like sag, gallop, icing, etc.

(d) Improved situational awareness of changing transmission conditions provides another tool for improving system reliability. For example, operators will be able to identify conditions such as ice accumulation as they emerge, rather than after an outage occurs, allowing for proactive steps to mitigate potential customer interruptions. Visibility into transmission line capacities allows NS Power to better optimize the assets that are already in place to serve customers. This can have beneficial impacts to the modeling of, and decision-making for, the most economically prudent dispatch of generation resources available on the system. These benefits are further discussed in IR-4, IR-9, IR-11, and IR-15.

Request IR-4:

In the Description, NS Power noted that "These conditions are continuously updated in NS Power's SCADA system, analyzed, and displayed in real time to the System Operators to enable critical decision making in support of reliable transmission operations."

(a) Please explain how system operators would use the provided information to make critical decisions, compared to operating without DLR systems.

(b) Please explain how other teams, such as System Planning and Security, would use the data to support their work, compared to working without the proposed system.

(c) Please explain the overall benefits to the system reliability, cost savings, and regulatory requirements.

Response IR-4:

(a) With DLR in place, System Operators gain real-time visibility into line conditions that would otherwise not be available. For example, sag measurements may indicate conductor overheating or icing, depending on seasonal conditions. Using this information, the System Operator can make timely decisions, such as reducing line loading to mitigate sag or adjusting system flows to reduce risk during icing events. In the absence of DLR, these conditions would be inferred from less precise seasonal ratings or would only be detected after an event occurred, reducing the Operator's ability to proactively manage the system.

(b) The DLR solution can reveal additional MW capacity in real time that can safely flow on these transmission lines than was previously available through Seasonally Adjusted Ratings, which are conservative ratings due to a lack of real time environmental conditions, that are typically updated in early Summer and late Fall depending on a marked change in weather that would indicate a move to the next season. This information can be a factor when making overall system operation decisions. The additional visibility of events occurring on the transmission lines can also be helpful for the NS Power System Security Engineering team to work with System Operators to effectively plan impact avoidance for emerging event (i.e. storms or planned outages) planning. This information will also be helpful during post-system disturbance event reviews.

(c) Overall benefits to system reliability, beyond what is noted above, include the early detection of conditions that could negatively impact transmission lines and the avoidance of issues that could result in customer outages. Improved accuracy and visibility of real-time environmental and asset (line) condition monitoring related to conditions such as sag, gallop, and conductor creep, will contribute to strengthening overall transmission reliability. For example, if a transmission line experiences galloping under normal conditions, it may lead Transmission and Reliability Engineers to conduct more detailed assessments of conductor condition and work to proactively resolve concerns before they become larger issues.

This project is justified based on reliability improvements rather than on a cost savings basis. Cost savings have not been estimated due to the unknown variables impacting quantification.

In terms of regulatory requirements, the vendor has published the potential MW capacity gains experienced by other customers as up to 40% during 50% of the time and up to 20% during 90% of the time. FERC has issued a Notice of Proposed Rule Making (NOPR)[1] that could require Transmission System Owners to have DLR installed on their most critical transmission lines; however, it has not been finalized. In the event FERC does reach the point of an official regulation, NS Power will be compliant.

[1] Explainer on the Implementation of Dynamic Line Ratings | Federal Energy Regulatory Commission

Request IR-5:

In March of 2024, NS Power conducted an RFP seeking a suitable vendor for this implementation. Eight vendors responded and all responses were reviewed in detail. The final decision and contract award was based on meeting the RFP key criteria and best suitability to NS Power operations…

(a) Please provide a summary of the tender evaluation results that led to the selection of the vendor.

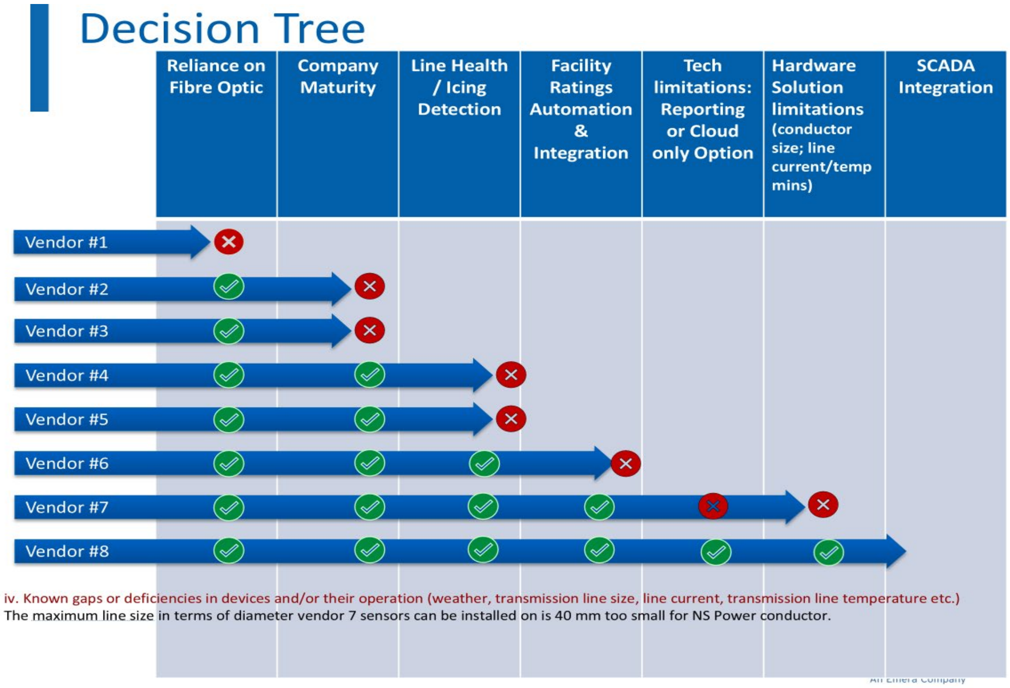
(b) Please provide detailed technical and functional reports for the accepted system.

(c) Please explain the estimated maintenance frequency and costs for the system.

(d) Please list other FERC regulated utilities who use a similar technology.

Response IR-5:

(a) The table below represents the vendor evaluation results.



Vendor #8 was successful in meeting all technical and project requirements set by NS Power based on their response to the RFP as well as follow up discussions.

(b) Please refer to Confidential Attachment 1 for the Technical Solution Overview provided by the selected vendor.

(c) Annual licensing and hosting fees are [redacted] CAD annually with an anticipated additional $12,000 in increased cellular airtime costs. There are no other maintenance or solution support fees. There are no maintenance requirements for the DLR Sensors.

(d) NS Power can not specifically comment on FERC-regulated utilities using this technology; however, in the United States, Pennsylvania Power and Light, Arizona Public Service, Southern California Edison, Exelon, National Grid, and the New York Power Authority all use this technology. In Europe, Elia, STATNETT, SVK, 50HERTZ, RTC, and Energinet utilize this technology. In Canada, Hydro Quebec, BC Hydro, ATCO, and NLH are also using this technology.

CI 47751 ECC Dynamic Line Rating Implementation NSEB IR-5 Confidential Attachment 1 has been removed due to confidentiality.

Request IR-6:

(a) Please provide more details about NRCan funding, including all conditions. Has NS Power received the funding already?

(b) What would be the impact on the overall project if the Board refuses the application again?

Response IR-6:

(a) All conditions can be found in Confidential Attachment 1, which includes the funding agreement and amendments. The NRCan funding for this project was available for eligible costs from October 11, 2023, until March 31, 2025. Eligible costs included project-specific labour, contracting, consulting, software, and materials. Overhead costs were not eligible. Project costs within the funding program timeframe were submitted in June 2025, approved in July 2025, and the Project received 100% reimbursement on those eligible costs, representing 71 percent of the total project costs. All available funding in the agreement has been received and is not conditional on NSEB approval.

(b) In a scenario where the Board denied the application, the Company would need to review the decision and rationale for any such denial to determine impacts.

CI 47751 ECC Dynamic Line Rating Implementation NSEB IR-6 Confidential Attachment 1 has been removed due to confidentiality.

Request IR-7:

In Why do this project now, NS Power noted that "Depending on the scope and timeline of FERC's adjustments and subsequent NERC compliance requirements, NS Power will likely be required to implement new technology across its bulk electric system."

(a) Please explain if NS Power is currently subject to any directives from NERC or other regulatory body to implement the DLR.

(b) If so, please provide detailed information and deadlines.

(c) If not, please explain why NS Power made this conclusion, and what is the estimated timeline for possible enforcement?

(d) For other utilities under NERC compliance, how many utilities have adopted the DLR system?

(e) Please explain how the new DLR system meets the applicable requirements and explain whether there are any formal standards or regulations from FERC, NERC, or other relevant authorities.

Response IR-7:

(a) NS Power is not currently subject to any directives from NERC or any other regulatory body requiring implementation of the DLR.

(b) N/A.

(c) NS Power is aware that FERC has issued a Notice of Proposed Rule Making (NOPR)[1] that, if finalized, could require Transmission System Owners to install DLR on their most critical transmission lines. The NOPR remains active, and FERC continues to seek feedback from US utilities. The timeline for possible enforcement is not yet known. NS Power is monitoring these developments closely.

(d) Among Canadian utilities subject to NERC Compliance, BC Hydro and Hydro Quebec currently have these DLR systems installed.

(e) Requirements related to DLR have been under development since 2024 and have not yet been formalized by FERC/NERC. In the event FERC does reach the point of an official regulation, NS Power will be well situated to achieve compliance based on the work undertaken through this project.

[1] Explainer on the Implementation of Dynamic Line Ratings | Federal Energy Regulatory Commission

Request IR-8:

(a) Please explain NS Power's plan to expand the proposed DLR technology to more transmission lines, and what the selection strategy is for selecting those lines.

(b) Please explain the timeline of the proposed expansion of the DLR technology.

(c) Does NS Power expect to get more federal fundings for future DLR projects?

Response IR-8:

(a) Consistent with its risk-based decision-making approach, NS Power would target any future expansion of DLR application based on the mitigation of risk on the transmission system. Using this approach, the Company anticipates that remaining lines in the Bulk Electric System (BES) could be considered for potential application of this technology. Similar to the Nova Scotia to New Brunswick and Cape Breton transmission corridors, these BES lines form the backbone of the NS Power system and are critical to system reliability.

Mitigating the risk from extreme event impacts through improved situational awareness as well as maximizing capacity on these key lines would be expected to deliver the largest benefit to customers. Selection of the specific lines and corridors within this subset would be done via risk assessment by Asset Strategy Committees and informed as appropriate by NS Power subject matter expert input. Further expansion beyond the BES lines may be considered based on a combination of reliability needs, capacity constraints, or other relevant factors. At this time, NS Power is not actively planning DLR expansion beyond the BES.

(b) No timeline has been established for any expansion beyond the initial set of lines proposed in this application.

(c) NS Power does not expect additional funding support for future DLR projects, as federal funding program availability changes over time. However, the Company would explore any available opportunities for cost mitigation at the time of any future expansion.

Request IR-9:

In the description, NS Power noted that the proposed Grid Enhancing Technology (GET) tools will improve "72-hour forecasting of ratings", and "support of reliable transmission operations". In addition, it would be available for system planning, system security engineering and other teams to support overall asset management strategies. Please elaborate on the above benefits and explain the following:

(a) NS Power's process to mitigate the extreme events with the GET in place compared to without GET in place.

(b) Explain the financial benefits with and without the GET.

(c) Explain the reliability benefits with and without the GET during such events.

(d) Explain if the GET system can reduce the unavailability of transmission lines during extreme weather events. If so, please explain how, and if not, please explain why not.

(e) Explain how the GET tools mitigate transmission congestion risks and enhance carbon reduction.

Response IR-9:

(a) The implementation of Dynamic Line Rating (DLR) sensors allows for NS Power's continuous monitoring of conductor conditions along the full length of a transmission line. During extreme weather events, this real-time monitoring provides valuable situational awareness that can be leveraged by NS Power personnel to undertake mitigation measures, as appropriate. Without data from DLR sensors, NS Power depends on indications from Environment and Climate Change Canada (ECCC) weather stations that may not provide necessary data and/or provide granular enough coverage to assess these risks, particularly where localized conditions such as freezing rain vary significantly across a line. Under these lower-awareness conditions, NS Power is frequently required to deploy field resources to visually monitor transmission lines for adverse conditions (such as signs of icing). This approach is constrained by resource availability, limited visibility of the rights-of-way (ROW) and lines at night, and the sheer length of some lines. A DLR sensor-enabled approach provides continuous monitoring of conditions that can be used to make more informed and effective decisions on how to respond without requiring field resources to remain staged within ROWs.

(b) Economic benefits from DLR are primarily a result of two factors: improved ability to respond appropriately to adverse weather events, as described in part (a), and more transmission system flexibility associated with additional available line capacity. As this project is justified on reliability improvement and not cost savings, NS Power has not performed a quantitative economic analysis.

As detailed above, continuous monitoring of line conditions during adverse weather events improves NS Power's ability to respond appropriately to events. It reduces the need to proactively dispatch field crews to monitor transmission lines and gives system operators better situational awareness. This allows them to make more effective and economic generation dispatch decisions, rather than relying on more conservative measures, such as limiting transmission flows, based on the possibility of freezing rain in the area.

As Nova Scotia continues to transition towards a lower-carbon generation mix, the ability to accommodate increased penetration of renewable generation is critical. The potential additional line capacity enabled by a DLR installation allows NS Power's System Operators to leverage additional, lower-cost generation or imports that may have otherwise been unavailable due to transmission system constraints. During periods of higher winds where the curtailment of wind generation may have been necessary due to capacity constraints, DLR can assess and incorporate the positive influence of the same winds on improving conductor capacity (through convective cooling) to accommodate increased flows. This maximizes available wind energy compared to static ratings. Additionally, as more generation interconnections are introduced, DLR provides an opportunity to potentially defer, reduce the scope, or avoid some transmission line upgrades by reducing the likelihood of system capacity limitations.

(c-d) The DLR technology is a monitoring and analysis tool, providing increased situational awareness to NS Power personnel. It is not designed or intended to directly eliminate the likelihood of a transmission line outage due to adverse conditions such as icing on a line's conductor due to freezing rain or structure failure due to extreme wind loading. It does not reinforce these assets directly to withstand these external forces. However, by providing early indications of emerging issues such as increasing ice loading on a line's conductor, NS Power personnel can take appropriate mitigating measures to address the potential loss of a line (including reducing line flows, strategic generation dispatch, and dispatching field resources to impacted areas), thereby reducing or eliminating further negative impacts to the NS Power system (including activation or Remedial Action and Special Protection Schemes that may proactively trip other transmission lines to support system stability) and outages to customers.

In the case of the November 2018 ice storm, unexpected extreme icing conditions led to the loss of multiple transmission lines (including the NB Import and CB Export corridors) and ultimately resulted in a significant under-frequency load shedding event impacting over 250,000 NS Power customers. Had the improved situational awareness from DLR technology been available, System Operators and other personnel could have taken action in advance of the sudden loss of key transmission system elements to proactively put NS Power's system in a more resilient state, significantly reducing the likelihood of system instability, including the loss of otherwise un-iced lines due to various protection schemes, and ultimately reducing customer impacts.

(e) With additional information on transmission line conditions (as discussed in IR-1 part (b)) provided by DLR sensors, more accurate estimates of available line capacity can be made in real-time. This enables the identification of additional transmission line capacity when conditions allow that can be used by system operators to reduce transmission system congestion that could otherwise emerge if using static rating limits. As a result of the reduced system constraints under favourable conditions, system operators can incorporate additional renewable generation onto the grid compared with historical approaches.

Request IR-10:

In the Why do this project now, NS Power states "There is currently a project in progress (C0061525 - Facility Ratings Project) to implement an Ambient Adjusted Rating (AAR) solution on all Transmission lines. This combined approach to have AAR…". Transmission line ratings based on AAR are considered more dynamic than static and seasonal ratings. Compared to static and seasonal ratings, please:

(a) Explain the capacity increase in MW due to AAR.

(b) Explain the capacity increase in MW due to DLR.

(c) Explain how AAR and DLR compliment each other, identify any potential conflicts, and clarify whether NS Power plans to operate them in parallel.

(d) Provide the rationale to maintain both systems.

Response IR-10:

(a) Based on estimates from the vendor indicating typical additional capacity gains, there is potential to see available MW increases of up to 10% up to 50% of the time for AAR equipped lines compared with static/seasonal ratings. Specifics of the line, environmental conditions, and non-environmental restrictions could result in higher or lower capacity changes.

(b) Based on estimates from the vendor indicating typical additional capacity gains, there is potential to see available MW increases of up to 40% up to 50% of the time and 20% up to 90% of the time for DLR equipped lines compared with static/seasonal ratings. The specifics of the line, environmental conditions, and non-environmental restrictions could result in higher or lower capacity changes.

(c) All transmission lines at or above 69kv will have AAR implemented and the specific lines stated in the scope of this DLR Project will also be equipped with DLR sensors. Lines with DLR sensors would reflect real time/dynamic ratings but would default to AAR in the event of an unplanned loss of data from the DLR sensors. There are no conflicts and NS Power does plan to operate these solutions concurrently. DLR presents a more accurate measurement of available capacity (along with providing real-time situational awareness of emerging adverse conditions) compared to AAR. AAR, while more dynamic than seasonal (static) ratings, do not use the directly measured values of environmental conditions from DLR sensors. The combination of DLR and AAR offers a comprehensive solution, providing improved ratings for lower criticality lines from AAR, while leveraging the more precise DLR functionality provided by sensors on critical transmission lines.

(d) As outlined in part (c) above, both the DLR and AAR approaches are included in a comprehensive, integrated solution for ratings and situational awareness, and they leverage much of the same technology platform concepts respectively. The two solutions were designed to be compatible with one another. The combined AAR and DLR approach undertaken by NS Power leverages both the ability to effectively cover the full transmission system (AAR) and to ensure a more targeted application of detailed ratings and situational awareness where applicable on high criticality corridors (DLR).

Request IR-11:

In Matter M09508, NS Power's response to NSUARB IR-19, the utility provided a table listing unplanned interruptions to transmission lines corridor caused by weather between 2015 and November 2019.

(a) Add data from December 2019 to date and provide an updated table.

(b) Based on the table, please provide customer interruption records, the duration of each outage, the number of customers affected and the identified cause of each interruption.

(c) What percentage of the above interruptions are classified as momentary, and what percentage are classified as sustained?

(d) With the implementation of the DLR technology, please provide an estimated percentage reduction in total interruptions.

(e) How would the DLR system prevent the listed outages? What specific data from the DLR system would help to avoid the trip? Please elaborate.

(f) If not, please explain why not.

(g) Explain the consequences of a trip on the grid.

(h) What steps will be taken to restore the transmission line after the trip and the financial implications?

(i) What specific data from the DLR would help to avoid the trip? Please elaborate.

Response IR-11:

(a-b) Please refer to Attachment 1 for the table of events occurring on the CB Export and NB Import corridors caused by weather from 2015 to 2025.

(c) Of the events identified in Attachment 1, 55% were classified as momentary interruptions and 45% were classified as sustained interruptions.

(d-f) As described in IR-9 parts (c) and (d), the DLR solution is not designed nor intended to directly address the likelihood of an individual transmission line outage due to adverse conditions acting on a line, such as icing on a line's conductor due to freezing rain or structure failure due to extreme wind loading. However, the various changes in data and trends received from the DLR sensors related to the measured wind speed, temperature, tension, sag, and orientation of the line can be used to identify developing issues and to mitigate potential impacts, as appropriate. The various data points measured by each sensor are interpreted in real time by the DLR software to understand the line environment and identify abnormal conditions.

In cases where the unexpected loss of a transmission line or corridor would result in larger system impacts, such as in November 2018, advanced notice of emerging issues provided by the DLR sensors and software allows NS Power System Operators and other personnel to implement mitigation measures. This can have a positive impact on the overall system performance. For extreme events such as the November 2018 ice storm, NS Power estimates that with earlier knowledge of the developing adverse conditions, proactive actions to stage additional mainland generation and limit imports could have been taken and customer impacts could have been significantly reduced (by an estimated 50%). For more limited or localized outage cases, such as the loss of L-8001 due to icing in 2023, earlier indications such as those that can be provided by DLR sensors, followed by a mitigating action of reducing imports could have eliminated the resulting customer impact.

(g) As discussed above, the consequences of a transmission line trip can vary depending on the specific line, system conditions (including loading), availability of parallel paths (e.g. other lines out for maintenance), and the protection schemes in service and armed at the time of the event. The lines targeted by this project are part of the broader bulk transmission network and do not directly serve customer load. Under normal operating conditions, an unplanned trip of one of these lines may only have minimal system impact due to available transmission redundancy and the ability to re-route power flows. The implementation of DLR further enhances this system resilience by enabling increased line capacity under favorable conditions, reducing the likelihood of post-contingency overloads.

However, under stressed system conditions, the loss of one of these lines can result in increased loading on adjacent facilities. If those facilities become overloaded, Remedial Action Schemes (RAS) may operate to preserve bulk electric system stability. RAS actions can include under frequency load shedding (UFLS; disconnecting customers to reduce load and preserve grid stability). An example of this behaviour was the November 2018 ice storm, which resulted in the loss of critical transmission lines and subsequently the trigger of an UFLS event on mainland Nova Scotia.

(h) The process to restore a transmission line following a sustained outage depends on the circumstances of the outage, but would typically include the following steps:

- The line is patrolled to identify the cause of the fault and what repairs or other corrective actions required.
- Should environmental conditions be determined to be the cause of the outage, such as icing or galloping (wind), wait until conditions improve prior to restoring the line.
- Should repairs (or other actions like mechanical ice removal) be required, switching is undertaken to isolate the line and field crews are dispatched to perform repairs, as appropriate.

- Following completion of repairs or resolution of adverse conditions, switching is performed to restore the line.

The financial implications of line restoration depend strongly on the time needed to patrol as well as the severity and nature of damage (if any) to resolve. Events requiring long patrols and/or more complex repairs will result in higher costs of restoration.

(i) Please refer to parts (d-f).

Year	Line	Start Time	Restore Time	Interruption Type	Cause	Customer Impact	Customer Hours
2015	L-7004	7/22/2015 14:06	7/23/2015 2:02	Sustained	Lightning	0	0.00
2016	L-7003	10/11/2016 8:02	10/11/2016 11:39	Sustained	Salt Spray / Wind	0	0.00
2016	L-7004	10/10/2016 23:18	10/11/2016 1:07	Sustained	Wind	0	0.00
2016	L-7004	10/11/2016 1:21	10/11/2016 1:27	Sustained	Wind	0	0.00
2016	L-7004	10/11/2016 2:45	10/11/2016 14:39	Sustained	Wind	0	0.00
2016	L-7005	7/23/2016 16:40	7/23/2016 16:40	Momentary	Lightning	0	0.00
2017	L-7003	6/29/2017 14:46	6/29/2017 15:00	Sustained	Lightning	0	0.00
2017	L-7004	6/2/2017 15:34	6/2/2017 15:34	Momentary	Lightning	0	0.00
2017	L-7005	9/28/2017 9:22	9/28/2017 9:23	Momentary	Lightning	0	0.00
2017	L-8001	9/28/2017 5:44	9/28/2017 5:47	Sustained	Lightning	0	0.00
2018	L-6515	11/29/2018 3:53	11/29/2018 3:54	Momentary	Ice		
2018	L-6515	11/29/2018 3:55	11/29/2018 15:43	Sustained	Ice		
2018	L-7003	11/29/2018 5:36	11/29/2018 5:36	Momentary	Ice		
2018	L-7003	11/29/2018 5:41	11/29/2018 13:55	Sustained	Ice		
2018	L-7005	11/29/2018 6:10	11/29/2018 6:10	Momentary	Ice		
2018	L-7005	11/29/2018 6:29	11/29/2018 6:29	Momentary	Ice		
2018	L-7005	11/29/2018 6:33	11/29/2018 13:26	Sustained	Ice		
2018	L-7005	11/29/2018 13:30	11/29/2018 13:31	Momentary	Ice	214,446*	704,269*
2018	L-7005	11/29/2018 13:34	11/29/2018 13:34	Momentary	Ice		
2018	L-7005	11/29/2018 13:37	11/29/2018 17:25	Sustained	Ice		
2018	L-7005	11/29/2018 17:27	11/29/2018 17:28	Momentary	Ice		
2018	L-7005	11/29/2018 17:32	11/29/2018 17:35	Sustained	Ice		
2018	L-7005	11/29/2018 17:39	11/29/2018 17:39	Momentary	Ice		
2018	L-7005	11/29/2018 17:53	11/30/2018 18:43	Sustained	Ice		
2018	L-8004	11/29/2018 7:03	11/29/2018 13:32	Sustained	Ice		
2019	L-7003	11/30/2019 15:52	11/30/2019 15:53	Momentary	Ice	0	0.00
2020	L-7003	1/17/2020 14:28	1/17/2020 17:20	Sustained	Salt Spray / Wind	0	0.00

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Year	Line	Start Time	Restore Time	Interruption Type	Cause	Customer Impact	Customer Hours
2020	L-7003	8/25/2020 18:57	8/25/2020 18:58	Momentary	Lightning	0	0.00
2020	L-7004	1/17/2020 14:28	1/17/2020 14:29	Momentary	Salt Spray / Wind	0	0.00
2020	L-7004	8/25/2020 18:42	8/25/2020 18:59	Sustained	Lightning	0	0.00
2020	L-7004	8/25/2020 19:30	8/25/2020 19:31	Momentary	Lightning	0	0.00
2020	L-7004	8/25/2020 21:18	8/25/2020 21:18	Momentary	Lightning	0	0.00
2020	L-8004	8/25/2020 23:25	8/25/2020 23:37	Sustained	Lightning	0	0.00
2020	L-8001	8/25/2020 22:19	8/25/2020 22:27	Sustained	Lightning	0	0.00
2021	L-6515	4/4/2021 1:32	4/4/2021 20:23	Sustained	Freezing Rain	516	1,428
2021	L-7003	4/4/2021 5:28	4/4/2021 17:40	Sustained	Freezing Rain	0	0.00
2021	L-7003	5/8/2021 14:32	5/8/2021 14:33	Momentary	Wind	0	0.00
2021	L-7003	6/8/2021 17:34	6/8/2021 17:35	Sustained	Lightning	0	0.00
2021	L-8004	4/4/2021 4:38	4/5/2021 19:20	Sustained	Ice	0	0.00
2021	L-8001	1/8/2021 13:45	1/8/2021 19:24	Sustained	Ice	0	0.00
2022	L-6515	2/7/2022 13:50	2/7/2022 20:58	Sustained	Ice	1,482	9,149.87
2022	L-6515	9/24/2022 0:59	9/26/2022 18:31	Sustained	Wind	1,714	29,039.13
2022	L-7003	7/25/2022 18:45	7/25/2022 18:46	Momentary	Lightning	0	0.00
2022	L-7003	7/26/2022 1:38	7/26/2022 1:38	Momentary	Lightning	0	0.00
2022	L-7003	9/21/2022 14:08	9/21/2022 14:09	Momentary	Lightning	0	0.00
2022	L-7003	9/24/2022 1:51	9/24/2022 1:51	Momentary	Wind	0	0.00
2022	L-7003	9/24/2022 2:02	9/24/2022 2:02	Momentary	Wind	0	0.00
2022	L-7003	9/24/2022 2:05	9/25/2022 10:29	Sustained	Wind	0	0.00
2022	L-7003	9/26/2022 11:47	9/26/2022 11:47	Momentary	Lightning	0	0.00
2022	L-7004	7/26/2022 1:14	7/26/2022 1:15	Momentary	Lightning	0	0.00
2022	L-7004	8/17/2022 20:20	8/17/2022 20:20	Momentary	Lightning	0	0.00
2022	L-7004	11/27/2022 0:36	11/27/2022 0:36	Momentary	Salt Spray / Wind	0	0.00

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Year	Line	Start Time	Restore Time	Interruption Type	Cause	Customer Impact	Customer Hours
2022	L-7005	8/17/2022 22:08	8/17/2022 22:08	Momentary	Lightning	0	0.00
2022	L-7005	9/24/2022 0:45	9/25/2022 14:30	Sustained	Wind	0	0.00
2022	L-7005	9/26/2022 10:58	9/26/2022 10:58	Momentary	Lightning	0	0.00
2023	L-7003	6/15/2023 18:36	6/15/2023 18:36	Momentary	Lightning	0	0.00
2023	L-7004	6/15/2023 16:54	6/15/2023 16:54	Momentary	Lightning	0	0.00
2023	L-7004	12/4/2023 12:34	12/4/2023 12:34	Momentary	Snow	0	0.00
2023	L-8001	1/16/2023 5:31	1/16/2023 14:19	Sustained	Ice	53,349	78,658.89
2023	L-8001	7/22/2023 3:28	7/22/2023 3:28	Momentary	Lightning	0	0.00
2024	L-6515	7/21/2024 18:35	7/21/2024 18:35	Momentary	Lightning	1,502	0.00
2024	L-7003	8/4/2024 18:09	8/4/2024 18:09	Momentary	Lightning	0	0.00
2024	L-7003	8/4/2024 18:22	8/4/2024 18:22	Momentary	Lightning	0	0.00
2024	L-7003	12/5/2024 9:26	12/5/2024 9:30	Sustained	Wind	0	0.00
2024	L-7005	7/21/2024 18:37	7/21/2024 18:38	Momentary	Lightning	0	0.00
2024	L-7005	8/15/2024 14:45	8/15/2024 14:45	Momentary	Lightning	0	0.00
2024	L-8001	3/9/2024 10:46	3/9/2024 14:56	Sustained	Ice	9,581	6,946.41
2025	L-7003	6/6/2025 4:13	6/6/2025 4:13	Momentary	Lightning	0	0.00
2025	L-7004	7/11/2025 15:33	7/11/2025 15:39	Sustained	Lightning	0	0.00
2025	L-7004	7/11/2025 16:05	7/11/2025 16:07	Sustained	Lightning	0	0.00
2025	L-7005	12/3/2025 12:20	12/3/2025 12:20	Momentary	Ice	0	0.00

*Combined customer impacts from underfrequency load shedding resulting from the loss of the CB Export Corridor experienced on November 29, 2018.

Request IR-12:

Please explain how the proposed GET tools and DLR correlate to the Evergreen IRP and NS Power's progress to the 2030 renewable electricity target.

Response IR-12:

The Evergreen IRP identifies the required resources to meet load growth, coal phase out, and environmental policy measures, including the renewable energy targets in Nova Scotia with wind generation playing a lead role in achieving the path to 2030 renewable electricity targets. While the ECC Dynamic Line Rating Project will not change IRP assumptions, transmission system related projects that support grid reliability and optimize grid capacity to enable the dispatch of these new wind resources are critical to meet customer demand and to provide support in meeting the 2030 renewable energy targets while maintaining grid reliability. As Grid Enhancing Tools, including Dynamic Line Ratings, provide an accurate view of the real-time capacity of the transmission system, this allows NS Power to optimize its transmission assets. Please also refer to IR-9.

Request IR-13:

(a) Please explain NS Power's regular line inspection practice and maintenance for the proposed transmission lines.

(b) Please explain how the DLR system would impact the line inspection practice and the regular NS Power transmission line maintenance and any operation cost benefits.

(c) Has the current transmission system faced load carrying bottleneck and had to rely on the DLR to increase capacity? Please explain how the DLR can replace the need for a transmission system upgrade? Please explain the impact on NS Power's transmission system upgrade plan, include projects for new transmission lines, existing system upgrade or replacement, etc.

(d) Explain the DLR system benefits and impacts on NS Power's conventional operation and provide quantified benefits including financial and reliability.

(e) Please explain the potential real-time transmission capacity expansion with proposed DLR technology and why it is critical to NS Power's system.

(f) Please compare the benefits and disadvantages between the DLR and transmission system upgrade.

(g) Please clarify in plain language whether the proposed DLR could place transmission system equipment under prolonged overload conditions.

(h) If so, please explain whether this may reduce the equipment's expected lifespan.

(i) If not, please provide the reasons why.

Response IR-13:

(a) NS Power's Transmission Line Inspection program is a condition assessment activity designed to determine the asset health of both the individual structural components and the overall line. It consists of several elements designed to contribute to an understanding of line conditions for use in risk-based decision-making on maintenance and upgrades. Additionally, the inspection program allows for the continued accuracy of the Geographic Information System (GIS) modelled attribute data of transmission lines and structures.

All transmission lines are inspected at least once per year either via ground patrol or helicopter patrol. Aerial LiDAR surveys are also used to assess ground clearances and vegetation conditions, primarily on high-criticality NERC lines. The primary assessment of transmission lines is the ground patrol of all transmission structures. The ground patrol includes verification of structure and circuit attributes, measurement of ground and vegetation clearances, and a detailed assessment of the structure and sub-components. The information collected during the ground patrol is supplemented by due diligence helicopter patrols in years that a line is not ground patrolled.

For critical spans such as large river crossings, additional assessments are conducted using drone photo and video. The results of each inspection are logged in NS Power's GIS for review and development of interventions, as necessary. The frequency of the different inspection activities is determined based on the criticality of the transmission line, the recency of the previous inspection, and critical crossings. High criticality lines and crossings may be inspected multiple times in a single year using different methods as appropriate.

The prioritization of the corrective actions resulting from inspection findings, including replacement of deteriorated assets on a transmission line, follows NS Power's risk rating methodology in the Board-approved CEJC, using the assessed condition and criticality scores of each line. This methodology considers the results of the various equipment and right-of-way inspections, past outage events, potential impacts to customers and system, remoteness of the line, and safety or environmental risks.

(b) The typical line inspection practice detailed in part (a) above is not expected to be affected by the deployment of DLR on these lines. Based on indications from the DLR tool during extreme events, additional inspections on an as-needed basis to determine line condition following such events, such as assessing potential asset damage indicated by sag or orientation through the DLR Platform, may be warranted to ensure reliable operation.

(c) The DLR solution implementation is not complete and as such NS Power has not yet relied on DLR to meet capacity needs. There is not a current expectation that the implementation of DLR will completely replace NS Power's need for all Transmission System Upgrades in the future. As detailed in IR-9, this technology provides an opportunity to potentially defer, reduce the scope, or avoid some transmission line upgrades by reducing the likelihood of system capacity limitations., however, any of these potential alternatives would require study. As this implementation is not yet complete, the results will require a period of confirmation, rationalization and review before adjusting the transmission system maintenance or capital plans.

(d) Please refer to IR-9 and IR-11 for a detailed discussion of DLR benefits.

(e) The potential estimated increases in capacity are detailed in IR-1 and IR-4, with the potential benefits detailed in IR-9.

(f) The implementation of a DLR solution compared with a traditional transmission system upgrade have some similarities as well as some differences, including their functionality, effectiveness, and cost of installation/construction.

In terms of functionality, the DLR solution provides real-time situational awareness to NS Power personnel to make more informed decisions on system operations. A transmission line upgrade project provides no additional information into line conditions as no sensors or monitoring are involved.

With respect to effectiveness, beyond situational awareness (unavailable for upgrade projects), both solutions can provide an increase to line capacity. In the case of DLR, a real-time dynamic adjustment can be made depending on the environmental conditions' influence on existing line assets, while in the case of a line upgrade project, this would be a static increase to capacity depending solely on the asset properties. The scope of the upgrade project would determine the potential increase, with projects targeting larger increases requiring larger interventions (replacing/adding structures, replacing conductor).

With a sufficiently large scope, an upgrade project has the potential to significantly increase the capacity of a line with appropriately rated assets and a sufficiently large budget. DLR installations would maximize the capacity of the existing assets without line asset replacements, so there is a limit to potential capacity gains governed by the assets.

The cost of each solution also differs, sometimes significantly, depending on the approach. Line upgrade projects are capital intensive and require the replacement of existing equipment with larger, higher rated, assets. Over the length of a single long bulk electric system line, addressing all limiting assets in this manner would likely require a multi-million-dollar investment over multiple years to realize the benefit. By contrast, the installation of DLR can achieve both increased situational awareness (that line upgrades cannot) as well as line capacity increases, that can be executed much faster and at a lower cost. As detailed in IR-9, this technology can also reduce, defer, or avoid upgrades or new construction to connect new load or generating facilities. Furthermore, DLR can be a complementary technology should line upgrades ultimately be required, to maximize the available capacity of a new or upgraded line, and ultimately the value of capital investments made by NS Power and its customers.

(g) No. System Operating Limits and their associated alarms remain in place across the transmission system. These limits and alarms prevent line overloading. The DLR solution is programmed to respect these limits.

(h) N/A.

(i) The inputs and analysis of the DLR system works in concert with the constraints and limits of the transmission system equipment to produce dynamic ratings that are maximized given the actual environmental conditions (compared with static ratings) and in conjunction with all other equipment factors and limits already in place. The system's analysis would not calculate a rating based on actual environmental conditions that would exceed the rating of the most limiting piece of equipment (including a safety factor) preventing the possibility that equipment could be inadvertently operated in an overloaded position for an extended period.

Request IR-14:

(a) What work and associated costs on the transmission line would be required if a DLR system is not installed.

(b) Please explain whether any alternative options have been considered.

(c) Please provide an Economic Analysis Model (EAM) for the "Do Nothing" option.

Response IR-14:

(a) No additional work would necessarily be required should a DLR system not be installed on a given line, but no situational awareness information would be available to NS Power personnel to identify and mitigate emerging adverse conditions. With respect to improved line capacity, capital investment to realize increased capacity either through line upgrades and/or construction of a new line can vary depending on the corridor length, existing line clearances, and installed assets. Based on high-level estimates by NS Power subject matter experts, investments to increase static ratings and add capacity to similar corridors (~160 km) would be in the range of $70-220 million.

(b) With respect to situational awareness for NS Power personnel, no viable alternatives were found that can provide comparable functionality to DLR technology. Alternative approaches to situational awareness within DLR technology providers were evaluated during the RFP process to select the most suitable system. Although this project is not justified primarily on achieving increased capacity, a high-level estimate for the construction of a new transmission line along the Cape Breton Export corridor was used as an analog for capital costs.

(c) A "Do Nothing" approach is not considered a viable option for providing situational awareness functionality as it provides no input on transmission line condition and in light of a changing climate and the ongoing risk from extreme events would represent an increasingly unacceptable risk to the future reliable operation of NS Power's transmission system. While the Company expects some economic benefits from this project through reduced transmission outages, this project is not based on these financial benefits. Accordingly, an EAM has not been completed.

Request IR-15:

(a) Please quantify the expected benefits associated with this project (i.e., decreased congestion, improved reliability, and improved capacity) in terms of the expected NPV in cost savings and describe how this cost savings will outweigh the project's estimated NPV of capital and operating costs.

(b) Please provide a time frame over which these cost savings will occur.

Response IR-15:

(a-b) As discussed in IR-9 and IR-11, the primary benefits from the installation of DLR are associated with situational awareness during extreme events. The impact of more effective event mitigation resulting from improved situational awareness will vary strongly with the frequency and severity of such events in the future. Extreme event impacts are challenging to estimate due to the highly variable nature of each event, including the timing and actual weather conditions, and consequently the benefits of mitigating such events are likewise variable.

However, the costs of reactively responding to the unplanned loss of a key transmission corridor can be significant, including field response to undertake customer restoration. Depending on the event, this response cost could range from tens of thousands of dollars (such as icing of a single line), into the millions of dollars for a larger, more extreme event (such as a more widespread event with significant impacts across the province) depending on the exact system conditions. These costs do not include the potentially significant disruptions to reliable service experienced by customers during such extreme events. Given the scale of these events compared with this capital request (which is significantly reduced by the $5.2 million from the Federal Government), the mitigation of even a handful of events provides a net positive benefit for customers. Depending on the future events, NS Power anticipates these benefits would be realized sometime in the next five years.

Additionally, as noted in IR-12, transmission system related projects that support grid reliability and optimize grid capacity to enable the dispatch of these new wind resources are critical to meeting customer demand and ensuring 2030 RES targets are met while maintaining grid reliability. Since the Grid Enhancing Tools, including Dynamic Line Ratings, provide an accurate view of the real-time capacity of the transmission system and expose previously untapped capacity, this allows for the optimization of the transmission assets needed to meet energy delivery needs in alignment with customer demand and helps ensure that renewable energy sources can be maximized, avoiding curtailment due to transmission limitations, while meeting the renewable energy targets for 2030 and beyond.

Request IR-16:

What is the expected useful life of each of the components of this project (hardware, software, etc.)?

Response IR-16:

The software used for the operation of the DLR project will be maintained and updated regularly by the vendor. As it is a cloud-hosted Software-as-a-Service solution, there is no defined end-of-life timeline. The vendor indicates an estimated life of the DLR sensors to be 15 years; however, they have sensors installed that have surpassed that timeline.

Request IR-17:

Does NS Power anticipate any increase in operating and maintenance expenses due to this project? If so, please provide an estimate of these increases on an annual basis over the useful life of the components of this project.

Response IR-17:

Please refer to IR-5 (c).

Request IR-18:

In the Capital Project Detailed Estimate, please explain the following:

(a) The expense of Conference Attendance $4,113.

(b) The responsibility of Program Manager.

(c) The responsibility of each role under the Consulting category.

(d) Are there any continued software subscription fees for the application? And the estimated cost for the overall life of the system.

Response IR-18:

(a) The conference attendance expense was for NS Power personnel to attend the Centre for Energy Advancement through Technological Innovation (CEATI) industry conference to meet with leading DLR vendors to discuss and understand their offerings as well as with other utilities and subject matter experts to gain valuable learnings from AAR/DLR RFP evaluations, pilot projects, and full implementations. The information gained from this conference was incorporated into the overall project scoping and RFP development as well as the subsequent evaluation of vendor responses.

(b) The Program Manager key responsibilities are project governance for this and other related projects. These responsibilities include:

- financial management,
- initial needs assessment and project scoping for potential to pursue,
- capital project initiation and submission,

- RFP management and execution and subsequent vendor and consultant management,
- NS Power technology integration and adherence to internal implementation standards,
- resource acquisition and management,
- maintaining integrated view across projects and internal NS Power business units, and
- Federal funding acquisition and management.

(c) Under the Consulting category:

- The Project manager is responsible for overall project planning, solution development, integration, testing, training; go live and post go live support planning and hand off to operations.

- The Senior Business Analyst is responsible for facilitating workshops, working with vendor engineers in solution development specific for NS Power, updating system requirements, documenting procedural and technical specifications, updating processes, test development, training development, organizational change management, supporting project go live and hyper care phase as well as project closure activities and supporting business end users, system operators and Project Manager.

- The Business Analyst is responsible for capturing, documenting and sharing detailed transmission line specifications, working with NS Power Transmission System Engineers to ensure installation plan and appropriate document is in place for field execution, updating line specification documentation, test execution, supporting training delivery, updating process documentation, updating user access requirements, supporting project go live and hyper care phase and project closure activities.

(d) Please refer to IR-5 (c).

Request IR-19:

(a) Why did NS Power include the NB Import Line at this time rather than wait to evaluate the results of the sensors on the CBX line?

(b) Confirm the total number of sensors for this project and how many are ground-based sensors?

Response IR-19:

(a) NS Power chose to include L-8001 along with the CBX corridor in this project due to the line's high importance to the effective operation of the Company's Bulk Electric System and identified icing risk based on its previous outage events. The NB Import corridor is critical to NS Power's ability to manage its overall system to support both the integration of additional renewable energy and economic imports as well as providing a valuable inter-utility link for system stability and redundancy. Installation of the DLR solution on the L-8001 corridor will provide additional, detailed situational awareness information on corridor status, allowing NS Power personnel to make the most informed decisions on system operation for the benefit of its customers. Realizing these situational awareness benefits at this stage contributes immediately to improving reliability and generation dispatch. Additionally, this technology has a proven track record over many years with several utilities across Europe and North America.

(b) There are 129 sensors for this project. No sensors are ground based.

Request IR-20:

(a) Provide a list of all metrics that the sensors will measure and explain each in plain language.

Response IR-20:

(a) The table below represents metrics that the sensors will measure.

DLR Metric	Description
Maximal Sag (ft)	The decrease in clearance between the line and the ground.
Ambient Temperature (deg C)	The recorded temperature at the selected span.
Load (MVA)	The real time load of the line.
Ice Weight (kg/ft)	The amount of ice on the line per foot.
Rotation Angle (deg)	The change in the rotational angle of the sensor.